Impact of Combined Heat and Power on Energy Use and Carbon Emissions in the Dry Mill Ethanol Process

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

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The Partnership provides informational resources about CHP technologies, incentives, emissions profiles, and many other items on its Web site: www.epa.gov/chp. For more information contact Felicia Ruiz at (202) 343-9129 or Ruiz.Felicia@epa.gov.

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Executive Summary

Fuel ethanol is one of the fastest growing segments of U.S. industry. Driven by provisions of the renewable fuels standard (RFS) in the Energy Policy Act of 2005 that increased the mandated use of renewable fuels, including ethanol and biodiesel, and a phase-out of methyl tertiary butyl ether (MTBE) as an oxygenate for reformulated gasoline, production of ethanol has increased by more than 300 percent since 2000. In 2006 the industry's 110 operating plants produced 4.9 billion gallons of ethanol, an increase of 25 percent over the previous year. At mid 2007, there were 82 new ethanol plants and twelve expansions under construction, which will add close to 7 billion gallons of new production capacity by 2009,[1] far surpassing the RFS mandate of 7.5 billion gallons in 2012.

Historically, corn ethanol plants are classified into two types: wet milling and dry milling. In wet milling plants, corn kernels are soaked in water containing sulfur dioxide (SO_2), which softens the kernels and loosens the hulls. Kernels are then degermed, and oil is extracted from the separated germs. The remaining kernels are ground, and the starch and gluten are separated. The starch is used for ethanol production. In dry milling plants, the whole dry kernels are milled. The milled kernels are sent to fermenters, and the starch portion is fermented into ethanol. The remaining, unfermentable portions are produced as distilled grains and solubles (DGS) and used for animal feed. Dry mill plants have become the primary production process for fuel ethanol. All corn ethanol plants that have come online in the past several years are dry milling plants, and the Renewable Fuels Association estimates that essentially all new plants expected to come online in the next few years will also be dry milling plants.

Dry mill ethanol plants have traditionally used natural gas as the process fuel for production. Natural gas is used to raise steam for mash cooking, distillation, and evaporation. It is also used directly in DGS dryers and in thermal oxidizers that destroy the volatile organic compounds (VOCs) present in the dryer exhaust.

The industry has made great progress in reducing energy consumption since its start in the 1980s; to produce a gallon of ethanol, today's dry mill plants only use about half of the energy used by the earliest plants.[2] Still, natural gas prices are on the rise, and energy costs are second only to raw material costs in the dry mill process. These factors are driving the industry to undertake further efforts to reduce energy use, or to switch from natural gas to other fuels such as coal, wood chips, or even the use of DGS and other process byproducts.

Along with increased production efficiencies and expanded fuel capabilities, combined heat and power (CHP) is increasingly being considered as an efficient energy services option by many ethanol plant owner and financing groups. CHP is an efficient, clean, and reliable energy services alternative, based on generating electricity on site. CHP avoids line losses, increases reliability, and captures much of the heat energy normally wasted in power generation to supply steam and other thermal needs at the site. CHP systems typically achieve total system efficiencies of 60 to 80 percent compared to only about 50 percent for conventional separate electricity and thermal energy generation (see Figure 1). By efficiently providing electricity and thermal energy from the same fuel source at the point of use, CHP significantly reduces the total fuel used by a business or industrial plant, along with the corresponding emissions of carbon dioxide (CO_2) and other pollutants.

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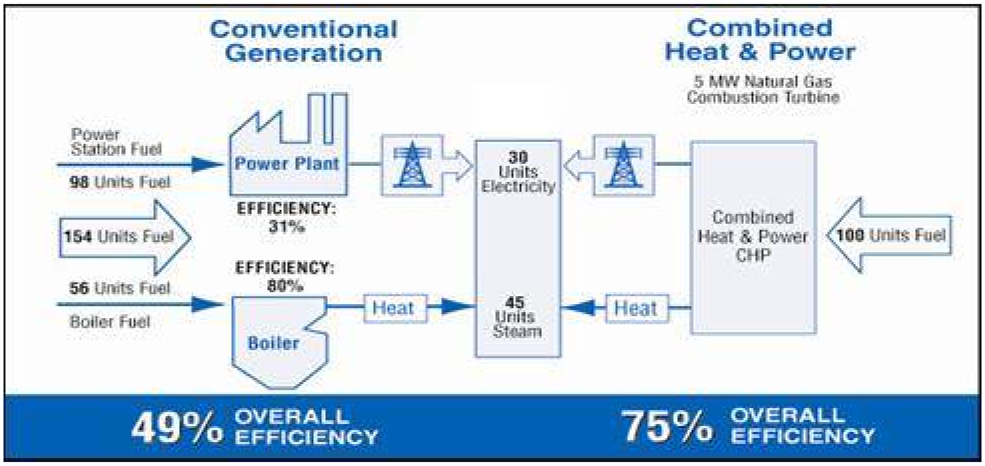
[1] Ethanol Industry Outlook 2007. Renewable Fuels Association. February 2007 and EPA CHPP data.
[2] Huo, H., Wang, M., & Wu, M. Life Cycle and Greenhouse Gas Emissions Impacts of Different Corn Ethanol Plant Types. Argonne National Laboratory. 2007.

Figure 1. Total Efficiency Benefits of Combined Heat and Power



To date, CHP and ethanol industry stakeholders have recognized that the efficiencies of CHP could further improve energy use patterns of dry mill ethanol plants, but the levels of impact have been unclear. This paper summarizes an analysis of state-of-the-art natural gas-, coal-, and biomass-fueled dry mill ethanol plants—comparing energy consumption and CO_2 emissions of the ethanol production process with and without CHP systems. Only the energy consumed in the dry mill conversion process itself was examined; the analysis does not consider the energy consumed in growing, harvesting, and transporting the feedstock corn, or in transporting the ethanol product itself. The analysis examines the impact of CHP on *total* energy consumption, including the impact on reductions in central station power fuel use and CO_2 emissions caused by displacing power purchases with CHP. The analysis shows that the use of CHP can result in reductions in total energy use of almost 55 percent over state-of-the-art dry mill ethanol plants that purchase central station power rather than use CHP. With certain CHP configurations, CO_2 emission reductions from using CHP to displace central station power even exceed the CO_2 emissions from the CHP system and ethanol plant, resulting in negative net CO_2 emissions for the plant compared with base case conditions.

Fuel selection at new dry mill ethanol plants is increasingly a decision based on perceptions of future natural gas prices and the cost and availability of alternatives such as coal or biomass. Whatever fuel is used, CHP increases the total energy efficiency of the dry mill process, providing reductions in both overall fuel use and total CO_2 emissions. CHP, using any of a suite of technologies, can be applied with a variety of fuels to save operating costs for the user and reduce overall fuel use and CO_2 emissions. These factors promise to be important considerations for the future of ethanol production as low carbon fuel standards are being evaluated at both the state and federal levels, and as carbon footprint becomes a critical industry measure.

CHP is not new at ethanol plants. Five gas turbine CHP systems similar to the cases described in this paper are currently operating at dry mill ethanol plants in the United States.[3] The first coal-fueled dry mill ethanol plants are just coming online, and at least one includes a steam

[3] Gas turbine CHP systems are installed at Adkins Energy LLC, Lena, Illinois; U.S. Energy Partners, Russell, Kansas.; Northeast Missouri Grain (POET Macon), Macon, Missouri.; Otter Creek Ethanol (POET Ashton), Ashton, Iowa; and Missouri Ethanol (POET Laddonia), Laddonia, Missouri.

turbine CHP system similar to the system described in this analysis.[4] In addition, a biomass-fueled CHP system is undergoing startup at an ethanol plant in Minnesota.[5]

Baseline Energy Consumption Profiles for Dry Mill Ethanol Production Facilities

Dry mill ethanol is the fastest growing market segment in the industry. It is comprised of dedicated ethanol facilities producing between 20 and more than 100 million gallons (MG) of ethanol per year. Energy is the second largest production cost for dry mill ethanol plants, surpassed only by the cost of the corn itself. Dry mill plants use significant amounts of steam for mash cooking, distillation, and evaporation. Steam or natural gas is also used for drying byproduct solids. (Dried distilled grains with solubles, or DDGS, are produced by drying the wet cake left over from the distillation process.) Electricity is used for process motors, grain preparation, and a variety of plant loads. A typical 50-MG-per-year (MGY) dry mill plant will have steam loads of 100,000 to 150,000 pounds per hour, and power demands of 4 to 6 megawatts (MW) depending on its vintage and mix of operations.

Table 1 provides energy consumption estimates (natural gas-, coal-, and biomass-fueled) for a 50-MGY state-of-the-art dry mill ethanol plant based on information from engineering and energy suppliers. The estimates reflect expected energy performance of new ethanol plants installed in 2006 and 2007. The assumptions in Table 1 are based on ethanol production only (e.g., no CO_2 recovery) and 100 percent drying of the wet cake for cattle feed product (DDGS).

The natural gas energy estimates are based on multiple packaged natural gas boilers generating steam for the production process. Natural gas is also used directly in the DDGS dryer, and in the regenerative thermal oxidizer that destroys the VOCs present in the dryer exhaust. The coal and biomass system estimates are based on fluidized bed boiler systems that integrate exhaust from a steam-heated DDGS dryer as combustion air to the boiler; in this case, VOC destruction occurs in the boiler itself and there is no need for a separate thermal oxidizer. The per-gallon electricity consumption is higher for the coal and biomass systems than for natural gas systems (0.90 kilowatt-hours [kWh]/gallon versus 0.75 kWh/gallon for natural gas) due to an estimated 20 percent additional power requirement for fuel handling, processing, and boiler ancillaries. The total steam consumption per gallon of ethanol is higher for the coal and biomass systems as well, reflecting the use of a steam DDGS dryer instead of a direct-fired system. The efficiency of the biomass fluidized bed boiler is lower than the coal boiler (72 percent versus 75 percent), reflecting a higher moisture content in biomass fuels. There is no direct fuel consumption for either a DDGS dryer or a thermal oxidizer in the coal or biomass-fueled systems.[6]

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[4] Central Illinois Energy in Canton, Illinois., is a 37 million gallons (MG) per year plant fueled by coal fines and coal. It incorporates a fluidized bed boiler/steam turbine CHP system.
[5] Central Minnesota Ethanol in Little Falls, Minnesota., is installing a biomass gasifier, fluidized bed boiler system with a steam turbine generator.
[6] The configurations evaluated represent typical state-of-the-art dry mill plants for each of the fuels. There are, however, a number of variations in use. Several natural gas-fueled plants generate a majority of their process steam using heat recovery boilers on the exhaust of nonregenerative thermal oxidizers. There is at least one coal-fueled plant that uses natural gas in a DDGS dryer and thermal oxidizer.

Table 1. Energy Consumption Assumptions for State-of-the-Art Dry Mill Ethanol Plants[7]

	Natural Gas-Fueled Plant	Coal-Fueled Plant	Biomass-Fueled Plant	References
Plant Capacity, MG/yr	50	50	50	
Ethanol Yield, Gal/bushel	2.8	2.8	2.8	1
Operating Hours	8,592	8,592	8,592	
Electric Consumption, kWh/Gal	0.75	0.90	0.90	Nat gas: 1,2; Coal: 2,4
Average Electric Demand, MW	4.4	5.2	5.2	Calculated
Annual Electric Consumption, MWh	37,500	45,000	45,000	Calculated
Boiler Type	Packaged	Fluidized Bed	Fluidized Bed	1, 2, 4, 5
Boiler Efficiency, percent (HHV[8])	80%	78%	72%	4, 5
Boiler Fuel Use for Process Steam, Btu/Gal	21,500	22,050	22,050	Nat gas: 1,2,3,4; Coal: 2,4,5
Process Steam Use, MMBtu/hr	100.1	100.1	100.1	Calculated
Annual Process Steam Use, MMBtu	860,000	860,000	860,000	Calculated
DDGS Dryer Type	Direct Fired	Steam	Steam	2, 5
Amount of Wet Cake Dried, percent	100%	100%	100%	Calculated
DDGS Dryer Fuel Use, Btu/Gal	10,500	NA	NA	1, 2, 3, 4
DDGS Dryer Steam Use, Btu/Gal	NA	14,200	14,200	4, 5
Annual DDGS Dryer Fuel Use, MMBtu	525,000	NA	NA	Calculated
Annual DDGS Dryer Steam Use, MMBtu	NA	710,000	710,000	Calculated
Thermal Oxidizer	RTO	Boiler	Boiler	2, 5
Thermal Oxidizer Fuel Use, Btu/Gal	330	NA	NA	4, 5, 6
Annual Thermal Oxidizer Fuel Use, MMBtu	16,500	NA	NA	Calculated
Total Annual Steam Use, MMBtu	860,000	1,570,000	1,570,000	Calculated
Total Annual Boiler Fuel Use, MMBtu	1,075,000	2,015,000	2,183,000	Calculated
Total Annual Fuel Use, MMBtu	1,616,500	2,015,000	2,183,000	Calculated
Total Fuel Use, Btu/Gal	**32,330**	**40,260**	**43,660**	Calculated

References for Table 1:

1. "Dry Mill Ethanol Plants," Bill Roddy, ICM, Governors' Ethanol Coalition, Kansas City, Kansas, February 10, 2006.
2. Personal Communications with Matt Haakenstad, U.S. Energy Services.
3. "Thermal Requirements: Coal vs. Natural Gas," Casey Whelan, U.S. Energy Services, Fuel Ethanol Workshop, Milwaukee, Wisconsin, June 20, 2006.
4. Personal communications with Steffan Mueller, University of Illinois at Chicago; data from Henneman Engineering
5. "Research Investigation for the Potential Use of Illinois Coal in Dry Mill Ethanol Plants," Energy Resources Center, University of Illinois at Chicago, October 2006.
6. Energy and Environmental Analysis, Inc. estimates.

[7] "State-of-the-art" reflects the energy performance of new dry mill ethanol plants in 2006 and 2007.

[8] All of the efficiencies and energy consumption values quoted in this paper are based on higher heating value (HHV) fuel consumption, which includes the heat of condensation of the water vapor in the combustion products. Engineering and scientific literature often use the lower heating value (LHV), which does not include the heat of condensation of the water vapor in the combustion products. The HHV is greater than the LHV by approximately 10 percent for natural gas, 6 to 8 percent for oil (liquid petroleum products), and 5 percent for coal.

The Impact of CHP on Plant Energy Consumption Profiles

Based on the energy-use assumptions outlined in Table 1, an analysis was conducted of the relative energy consumption of conventional, non-CHP, dry mill ethanol boiler plant designs compared with those incorporating CHP. The analysis was based on state-of-the-art, 50 MGY natural gas-, coal-, and biomass-fueled ethanol plants as described above. Three base case plant designs were considered:

- Natural Gas Base Case—Conventional (non-CHP) natural gas boiler, gas-fired DDGS dryer, and regenerative thermal oxidizer.
- Coal Base Case—Non-CHP fluidized bed coal boiler with exhaust from a steam-heated DDGS dryer integrated into the boiler intake for VOC control.
- Biomass Base Case—Non-CHP fluidized bed coal boiler with exhaust from a steam-heated DDGS dryer integrated into the boiler intake for VOC control.

All three base cases were assumed to operate 24 hours per day, seven days per week, for 51 weeks per year (8,592 hours). Table 2 presents the hourly steam and electric demands of the three base cases using the energy consumption assumptions outlined in Table 1. Steam consumption is based on delivering 150 pounds per square inch gauge (PSIG) saturated steam to the process (energy input from the boiler of 1,022 Btu [British thermal units] per pound of steam).

Table 2. Base Case Steam and Electric Demands for 50 Million Gallons per Year Dry Mill Ethanol Plants

	Natural Gas Base Case	Coal Base Case	Biomass Base Case
Plant Capacity, MGY	50	50	50
Operating Hours	8,592	8,592	8,592
Electric Consumption, kWh/Gal	0.75	0.90	0.90
Average Electric Demand, MW	4.4	5.2	5.2
Annual Electric Consumption, MWh	37,500	45,000	45,000
Process Steam Use, MMBtu/hr	100.1	100.1	100.1
Dryer Steam Use, MMBtu/hr	NA	82.6	82.6
Total Steam Use, MMBtu/hr	100.1	182.6	182.6
Annual Steam Use, MMBtu	860,000	1,570,000	1,570,000

Five CHP system configurations were evaluated and compared to the three base case non-CHP ethanol plants:

- *Natural Gas CHP*

  Case 1: Gas turbine/supplemental-fired heat recovery steam generator (HRSG)—Electric output sized to meet plant demand; supplemental firing needed in the HRSG to augment steam recovered from the gas turbine exhaust.

Case 2: Gas turbine with power export—Thermal output sized to meet plant steam load without supplemental firing; excess power generated for export.

Case 3: Gas turbine/steam turbine with power export (combined cycle)—Thermal output sized to meet plant steam load without supplemental firing; steam turbine added to generate additional power from high-pressure steam before going to process; maximum power generated for export.

- *Coal CHP*

Case 4: High-pressure fluidized bed coal boiler with steam turbine generator—Exhaust from steam-heated DDGS dryer integrated into the boiler intake for combustion air and VOC destruction.

- *Biomass CHP*

Case 5: High-pressure fluidized bed biomass boiler with steam turbine generator—Exhaust from steam-heated DDGS dryer integrated into the boiler intake for combustion air and VOC destruction.

Table 3 provides the CHP system descriptions and performance characteristics assumed for the analysis. Note that in Case 1—the gas turbine sized to meet the plant's electricity load—the exhaust from the gas turbine can only provide about 23 percent of the plant's steam needs. A duct burner in the HRSG is used to provide supplemental heat to generate the additional steam at high efficiency (approaching 90 percent). In Cases 2 and 3, the system is sized to meet the thermal needs of the plant without supplemental firing. In Case 2, the simple-cycle gas turbine produces 22.1 MW of power and 100 MMBtu per hour of steam. The electrical output far exceeds the average 4.4 MW power requirements of the plant, meaning that excess power would need to be exported to the grid. This configuration might be installed by a third-party service provider, or as a joint venture between an ethanol plant and the servicing utility. The Case 3 combined-cycle configuration further increases the power output of the CHP system to 30 MW. It does so by producing higher-pressure steam in the HRSG and driving a steam turbine to generate additional power before sending steam to the production process at 150 PSIG. Again, this configuration might be installed by a third-party energy provider or a utility-ethanol plant joint venture.

The sizes of the coal- and biomass-fueled steam turbine systems are set by the steam demand and power requirements of the plant. The CHP systems analyzed consist of 180,000 pounds per hour fluidized bed boilers producing steam at pressures and temperatures higher than the process requirements (600 PSIG and 600°F). The entire steam output of the boilers enters back-pressure steam turbines where 5 MW of electricity is generated before the steam exits the turbine at the 150 PSIG pressure conditions required for the process.[9] The capacity of the steam turbine generator is approximately 95 percent of the average plant power demand, ensuring that all generated power can be used on site.

[9] Additional power could be generated in Cases 4 and 5 with higher-pressure boilers. Power output was limited in these cases to ensure all output could be used onsite, and to minimize incremental boiler costs over the base cases.

Table 3. CHP Case Descriptions

	CHP Case 1	CHP Case 2	CHP Case 3	CHP Case 4	CHP Case 5
CHP System	Gas Turbine/Fired-HRSG	Gas Turbine/HRSG	Gas Combined Cycle	Coal Boiler/Steam Turbine	Biomass Boiler/Steam Turbine
Net Electric Capacity, MW	4.0	22.1	30.0	5.0	5.0
System Availability, percent	97%	97%	97%	95%	95%
Annual Operating Hours	8,334	8,334	8,334	8,334	8,334
Annual Electric Generation, MWh	33,337	184,187	250,027	40,812	40,812
CHP Steam Generation, MMBtu/hr	22.5	100.1	100.1	204.3	204.3
Supplemental Firing Steam, MMBtu/hr	77.6	NA	NA	NA	NA
Process Steam Generation, MMBtu/hr	100.1	100.1	100.1	182.6	182.6
Annual Process Steam Generation, MMBtu	834,200	834,200	834,200	1,521,800	1,521,800

Table 4 compares the overall *plant* energy consumption profile of the three natural gas CHP cases to the natural gas base case. All three CHP cases increase the total fuel use at the plant, but plant electricity purchases are reduced by 89 percent. In Case 1, the fuel use increase is only marginal: about 6 percent more fuel use than the base case. In Cases 2 and 3, where much more power is generated than is needed at the plant, the increases are 62 and 90 percent, respectively.

Table 4. CHP *Plant* Energy Consumption Comparison—Natural Gas

Characteristics	Gas Base Case No CHP	CHP Case 1 Gas Turbine With Duct Firing	CHP Case 2 Gas Turbine With Export	CHP Case 3 Combined Cycle With Export
Plant Capacity, MGY	50	50	50	50
Average Electric Demand, MW	4.4	4.4	4.4	4.4
CHP Capacity, MW	0	4.0	22.1	30.0
CHP Availability, percent	n/a	97%	97%	97%
Electric Generated, MWh	**0**	**33,337**	**184,187**	**250,027**
Electric Purchased, MWh	37,500	4,163	4,163	4,163
Electric Exported, MWh	**0**	**0**	**150,850**	**216,690**
Annual CHP Steam, MMBtu	0	834,200	834,200	834,200
Annual Boiler Steam, MMBtu	860,000	25,800	25,800	25,800
CHP Turbine Fuel Use, MMBtu	0	422,846	2,057,103	2,510,327
Duct Firing Fuel Use, MMBtu	0	718,533	0	0
Boiler Fuel Use, MMBtu	1,075,000	32,250	32,250	32,250
Dryer/TO Fuel Use, MMBtu	541,500	541,500	541,500	541,500
Total Plant Fuel Use, MMBtu	1,616,500	1,715,129	2,630,853	3,084,077
Total Plant Fuel Use, Btu/Gal	***32,330***	***34,303***	***52,617***	***61,682***

Table 5 compares the overall *plant* energy consumption profile of the coal and biomass base cases to their respective CHP cases. Again, both CHP cases increase the total fuel use at the plant to provide the additional energy contained in high-pressure steam that will be turned into power in the steam turbine. Plant electricity purchases are reduced by 93 percent for both cases.

Table 5. CHP *Plant* Energy Consumption Comparison—Coal and Biomass

Characteristics	Coal Base Case No CHP	Case 4 Coal CHP Boiler/Steam Turbine	Biomass Base Case No CHP	Case 5 Biomass CHP Boiler/Steam Turbine
Plant Capacity, MGY	50	50	50	50
Average Electric Demand, MW	5.2	5.2	5.2	5.2
CHP Capacity, MW	0	5.0	0	5.0
CHP Availability, percent	n/a	95%	n/a	95%
Electric Generated, MWh	**0**	**40,812**	**0**	**40,812**
Electric Purchased, MWh	45,000	4,188	45,000	4,188
Electric Exported, MWh	0	0	0	0
Annual Boiler Steam, MMBtu	1,570,000	1,755,000	1,570,000	1,755,000
Annual Process Steam, MMBtu	1,570,000	1,570,000	1,570,000	1,570,000
Boiler Fuel Use, MMBtu	2,015,026	2,250,313	2,182,944	2,437,839
Dryer/TO Fuel Use, MMBtu	0	0	0	0
Total Plant Fuel Use, MMBtu	2,015,026	2,250,313	2,182,994	2,437,839
Total Plant Fuel Use, Btu/Gal	***40,300***	***45,005***	***43,660***	***48,760***

The economic value of CHP is a trade-off between capital costs, fuel costs at the plant, and decreased electricity purchases from the utility. While CHP increases the amount of fuel used at the plant in each of the CHP cases, it significantly reduces purchased electricity requirements. Whether this trade-off makes sense on an economic basis is site specific. It depends on the relative costs to the plant of purchased electricity and fuels; the capital and nonfuel operating costs of the CHP system; and the value of ancillary services, such as enhanced power reliability to the plant operator or the value of exported power, as in Cases 2 and 3.

The Impact of CHP on Total Energy Use and CO_2 Emissions

From an overall energy and environmental policy perspective, it is essential to examine the impact of CHP on *total* energy consumption. This evaluation includes the effect on reductions in central station power fuel use and CO_2 emissions caused by displacing power purchases with electricity generated on site by CHP. Table 6 compares the *total* energy consumption of the three natural gas CHP cases with the base case plant and central station fuel consumption.

Central station fuel use and CO_2 emissions were calculated based on the 2007 eGRID U.S. average fossil heat rate—equal to 10,215 Btu/kWh—and average fossil CO_2 emissions of 1,867 pounds per megawatt-hour (MWh). Transmission and distribution losses were assumed to be 7 percent based on U.S. Department of Energy estimates of average annual transmission and distribution system losses.[10] CO_2 emissions at the ethanol plant were calculated based on 117 pounds of CO_2 per MMBtu of natural gas consumed.

As shown in the table, CHP reduces both the total energy used by the dry mill ethanol process and the total CO_2 emissions. In Case 1, overall fuel use is reduced by 13 percent on a Btu-per-gallon basis, and CO_2 emissions are reduced by 21 percent on a pound-per-gallon basis. As more central station power is displaced in Cases 2 and 3, overall net fuel used to produce a gallon of ethanol, and associated net CO_2 emissions, are further reduced. In Case 3, CHP reduces total net fuel consumption by 55 percent; CO_2 emission reductions from displacing central station power exceed the CO_2 emissions at the plant itself, resulting in negative net CO_2 emissions for the CHP system compared with base case conditions.

Table 6. CHP *Total* Energy Consumption Comparison—Natural Gas

Characteristics	Base Case No CHP	CHP Case 1 Gas Turbine With Duct Firing	CHP Case 2 Gas Turbine With Export	CHP Case 3 Combined Cycle With Export
Plant Fuel Use				
Total Plant Fuel Use, MMBtu	1,616,500	1,715,129	2,630,853	3,084,077
Total Plant Fuel Use, Btu/Gal	***32,330***	***34,303***	***52,617***	***61,682***
Central Station Fuel Use				
Purchased Power—MMBtu	411,548	45,688	45,688	45,688
Export Power—MMBtu	0	0	-1,539,633	-2,211,628
Total Net Fuel Use, MMBtu	2,028,048	1,760,817	1,136,908	918,137
Net Fuel Use, Btu/Gal	***40,560***	***35,215***	***22,738***	***18,363***
Plant CO_2 Emissions, Tons/yr	94,565	100,335	153,905	180,419
Central Station CO_2 Emissions, Tons/yr	37,641	4,179	-136,639	-198,101
Net CO_2 Emissions, Tons/yr	132,206	104,514	17,265	-17,683
Net CO_2 Emissions, lb/Gal	***5.29***	***4.18***	***0.69***	***-0.71***

Table 7 compares the *total* energy consumption of the coal and biomass CHP cases with their respective base cases. Central station fuel use and CO_2 emissions were again based on the 2007 eGRID U.S. average fossil heat rate—equal to 10,215 Btu/kWh—and average fossil CO_2 emissions of 1,867 pounds per MWh. Transmission and distribution losses were assumed to be 7 percent based on DOE estimates of average annual losses. CO_2 emissions at the ethanol plant were calculated based on industry-accepted values of 220 pounds of CO_2 per MMBtu of coal. Biogenic biomass is considered carbon neutral—neither adding nor subtracting carbon emissions from the carbon cycle—and was assumed to have zero CO_2 emissions. As shown, CHP again reduces both the total energy used by the dry mill ethanol process and the total CO_2 emissions. CHP reduces overall fuel use by 9 percent and CO_2 emissions by approximately 5.6 percent in the case of coal. CHP provides a total fuel reduction of 8 percent in the case of biomass-fueled ethanol production and results in CO_2 reductions of 91 percent.

[10] No transmission and distribution losses were included in the calculation of central station fuel use and CO_2 emissions displaced by power exports from the CHP systems.

Table 7. CHP *Total* Energy Consumption Comparison—Coal and Biomass

Characteristics	Coal Base Case No CHP	Case 4 Coal CHP Boiler/Steam Turbine	Biomass Base Case No CHP	Case 5 Biomass CHP Boiler/Steam Turbine
Plant Fuel Use				
Total Plant Fuel Use, MMBtu	2,015,026	2,250,313	2,182,994	2,437,839
Total Plant Fuel Use, Btu/Gal	***40,300***	***45,005***	***43,660***	***48,760***
Central Station Fuel Use				
Purchased Power – MMBtu	493,858	45,962	493,858	45,962
Export Power – MMBtu	0	0	0	0
Total Net Fuel Use, MMBtu	2,508,884	2,296,275	2,676,852	289,801
Net Fuel Use, Btu/Gal	***50,178***	***45,925***	***53,540***	***49,675***
Plant CO_2 Emissions, Tons/yr	221,653	247,534	0	0
Central Station CO_2 Emissions, Tons/yr	45,169	4,204	45,169	4,204
Net CO_2 Emissions, Tons/yr	266,822	251,738	45,169	4,204
Net CO_2 Emissions, lb/Gal	***10.67***	***10.07***	***1.81***	***0.17***

Conclusions

As shown above, use of CHP can lower the overall fuel use and CO_2 emissions attributable to ethanol production at dry mill plants. Figure 2 compares the total fuel use impacts across the three base cases and five CHP cases. Note that the total fuel consumption—fuel consumed at the ethanol plant, as well as at the central station power facility to produce electricity purchased by the plant—is less for the base case natural gas ethanol plant than for either the coal or biomass base cases.

In all cases, fuel consumption at the *plant* increases with the use of CHP. However, *total net* fuel consumption is reduced, as electricity generated by the CHP systems displaces less efficient central station power. In the two natural gas CHP cases with excess power available for export (Cases 2 and 3), the displaced central station fuel represents a significant credit against increased fuel use at the plant. The total fuel savings for Cases 2 and 3 are 44 percent and 55 percent, respectively, over the natural gas base case.

Figure 2. Total Net Fuel Consumption for Dry Mill Ethanol Plants—Btu/Gallon

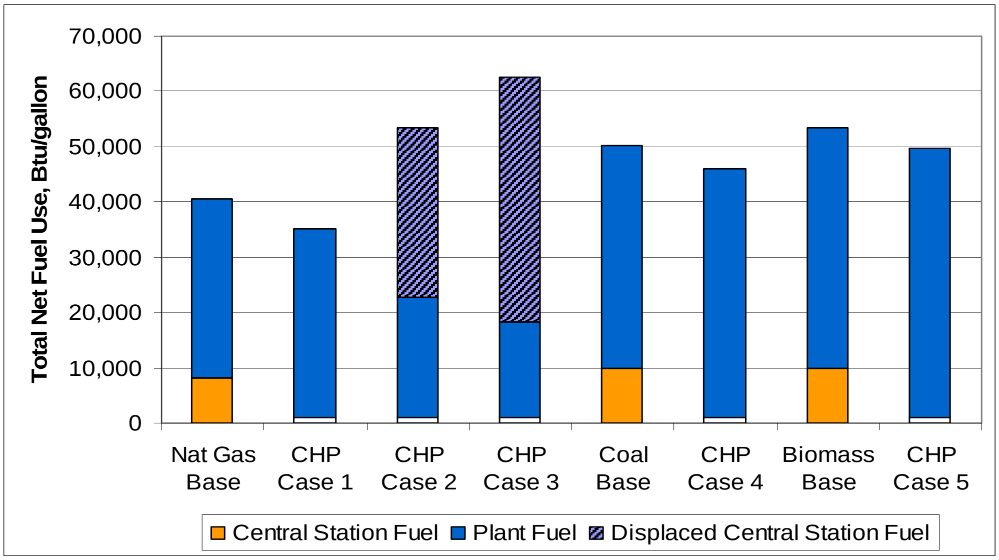

Figure 3 compares the impact of CHP on total CO_2 emissions. Total CO_2 emissions for the natural gas base case—CO_2 emissions at the ethanol plant as well as at the central station power facility to produce electricity purchased by the plant—are significantly lower than for the coal base case. CO_2 emissions for the biomass base case are the lowest, consisting of the central station emissions to provide purchased power to the plant.

Total CO_2 emissions are reduced for all CHP cases compared to their respective base case plants. Again, displaced central station emissions for Cases 2 and 3—the two natural gas CHP cases with excess power available for export—represent a significant CO_2 savings. Total net CO_2 emissions in Case 2 represent an 87 percent reduction in CO_2 emissions compared to the natural gas base case. Total plant CO_2 emissions for Case 3 are actually less than the displaced central station emissions, resulting in a negative (-0.71 pounds per gallon) net CO_2 emissions rate compared to the base case.

Figure 3. Total Net CO_2 Emissions for Dry Mill Ethanol Plants—Pounds/Gallon